INDEPENDENT SYSTEM OPERATORS AND BIOMASS POWER

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ABSTRACT

Momentum towards creating and establishing independent system operators (ISOs) has accelerated since the Federal Energy Regulatory Commission (FERC) issued its landmark open access transmission rule in 1996. ISOs may help combine individual utility transmission systems into more regional transmission networks, which ultimately will allow biomass companies to transmit power over longer distances while paying a single transmission rate. To the extent ISOs are combined or operated with power exchanges, however, biomass companies will likely face even more competitive market pressures. Operating experience with ISOs and power exchanges is quite limited, but the preliminary results show that short-term electricity market prices are quite low, probably too low for most biomass companies to compete against. Without policy measures, biomass companies may have to pursue strategic opportunities with short-term spot market sales, direct bilateral sales to customers, alternative power exchanges, and perhaps a "green" power market and sales to ancillary service markets. In addition, there likely will be greater price volatility in a restructured market, and biomass generators should be selling during those times.

Keywords: independent system operators, biomass, ancillary services

INTRODUCTION

Independent system operators (ISOs) are created when a transmission-owning utility or group of transmission-owning utilities transfer some or all operating control (but not ownership) over designated transmission facilities to an independent, nonprofit, or not-for-profit organization. ISOs may or may not operate a control area; dispatch transmission; run a power exchange or spot market; administer an ancillary services market and deliver ancillary services; conduct transmission planning; and, with transmission owners, expand transmission capacity.

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ISOs became an industry topic in 1995 when a bitter standoff in California between advocates of a central pool (poolco) and advocates of direct contracts between parties agreed to a separate power exchange and a separate system operator (the ISO, in this case). Since then and as of early 1998, another nine ISOs have been in various stages of discussion, negotiation, formation, and operation (see Table 1) (ICF Resources Inc., 1998). This group includes the Texas ISO that is operating in the Electric Reliability Council of Texas (ERCOT) and is not under jurisdiction of the Federal Energy Regulatory Commission (FERC). The amount of ISO activity suggests that the electric power industry has moved from an open access transmission mode that is focused on individual utilities, to an ISO mode in which efforts are devoted to developing a regional transmission tariff and an institution to support the emergence of regional power markets.

ISOs offer the potential for combining the now balkanized transmission system into several regional networks, perhaps with consolidated control areas and a single regional transmission tariff with little or no “pancaking” of transmission rates. (Pancaking of transmission rates occurs when power is shipped over more than one transmitting utility’s system, and the transmission customer pays for the capacity shipped over each utility’s system. In other words, a transmission customer who transmits 100 megawatts [MW] over three transmission systems pays for 300 MW of service). ISOs may also provide at least an interim solution for those that prefer divestiture of transmission by avoiding some of the legal difficulties of divesting transmission facilities that have been constructed with public and/or tax-exempt financing, and it allows policymakers to move ahead with restructuring initiatives.

Even so, considerable difficulty has arisen recently in the attempts to form some ISOs. In December 1997, a group of utilities led by FirstEnergy broke away from the planned Midwestern ISO to explore forming a smaller “sliver” ISO that would lie between the Midwestern ISO and the New England ISO (NE-ISO) and Pennsylvania-New Jersey-Maryland (PJM) ISO in the eastern United States (FirstEnergy, 1997). More recently, negotiations to form the Indego ISO, encompassing the Pacific Northwest, were suspended when the Bonneville Power Administration indicated it would not join, prompting many other utilities in the region to withdraw as well (Idaho Power, 1998).

A primary reason for some transmission owners’ reluctance to join ISOs is the difference in transmission rates among transmission owners, which can differ by as much as a factor of seven. As a result, transmission owners express concern there may be cost shifting from transmission owners with higher rates to transmission owners with lower rates. Therefore, although ISOs offer the potential of single tariffs and rates, almost all ISOs must go through a transition period before getting to this state. Generally, this involves creating transmission zones corresponding to the service territories of transmission owners, and transmission customers paying the rate corresponding to the zone where the

load is located. Even with this transition period, some transmission owners fear they may not recover their costs if they join an ISO[2] (Walton, 1998).
Furthermore, some transmission owners or other market participants may be reluctant or unwilling to join an ISO because of concerns that the tax-exempt financing used to finance these facilities may be jeopardized if for-profit market participants use these transmission facilities. Though investor-owned utilities control more than 70% of the nation’s transmission, the reluctance of municipal utilities and/or rural cooperatives to participate in an ISO may have important regional implications. For example, concerns about tax issues have been at least one of the reasons why the Los Angeles Department of Water and Power, holder of 28% of the state's transmission, has not joined the California ISO (Electric Utility Week, 1998). In addition, Bonneville Power Administration, controller of most of the transmission in the Pacific Northwest, believes congressional legislation may be required before it can join an ISO.

Consequently, there are concerns that ISOs may be too small, and/or that there may be “holes” in an ISO caused by parties that choose not to join. This issue may effectively minimize or even nullify the potential of one-stop shopping for transmission. Also, pancaked rates may not entirely disappear if there are many small ISOs, rather than a small group of large ISOs. Pancaked transmission rates may arise in a different way, however. They may occur in transactions between ISOs, or between ISO and non-ISO members. Therefore, the goals of avoiding pancaked transmission rates and developing regional, efficient electric markets or transmission markets may not be reached if the ISOs are too small.

These developments have prompted re-examination of several issues. Are ISOs a permanent institution or merely a stepping stone to an independent tariff administrator or to transmission-only companies? Can the electric power industry form ISOs voluntarily or must it be coerced into doing so? Should FERC intervene, and does it have the regulatory authority to do so? Should future national restructuring legislation include ISO provisions that specify minimally acceptable ISOs and require utilities to join or commit to an ISO? FERC, in fact, held a 2-day technical conference in Washington, D.C., and several regional conferences around the country, addressing these and other ISO-related questions.

[2] Walton indicates that transmission owners in the proposed Indego ISO with lower cost transmission systems faced transmission rate increases of up to 200% with a single, region-wide transmission rate, and 50% with a zonal transmission rate. Although this information is specific to the Indego ISO, the general issues of cost shifting and cost differentials among transmission owners have been problems affecting the formation of ISOs across the country.

Table 1. Summaries of ISO Proposals

Name	Planned Operation Date	Proposal Status	States Included	Power Exchange (PX)?	Control Areas	ISO Grid [a]	Congestion Pricing	Transmission Tariff
ISO-NE	Began Operating In July 1997	Conditionally Approved	CT, MA, ME, NH, RI, VT	ISO is PX	Single	69kV and up	Out-of-merit when capacity available	Postage stamp
NY ISO	Late 1998	Approved	NY, NJ	Separate PX	Single	115kV and up	LBMP	Zonal
PJM Interconnection	4/1/97	Approved	DC, DE, NJ, PA, MD, VA	ISO is PX	Single	69 kV and up	LBMP; fixed transmission rights for firm transmission service	Zonal
CA ISO	3/31/98	Approved	CA	Separate PX	Single	60 kV and up	User pays through adjustment bids	Zonal
ERCOT ISO	12/96	TX PUC approved	TX	No PX	Multi	69 kV and up	Re-dispatch; all users share costs	Postage stamp w/dist.
Indego	N.A.	Negotiations suspended	CO, ID, MT, NV, OR,UT, WA,WY	No PX	Multi	230 kV and up	Bids to reverse flow	Zonal
Midwest ISO	1999	Before FERC	IA, IL, IN, KY, MD, MI, MN,MO OH, PA, VA,WV, WI	No PX	Multi	100 kV and up	Re-dispatch, all load share costs	Zonal
Desert-STAR	2002	In planning	AZ, NM, TX, NV	No PX	Multi	230 kV and up	Bids to reverse flow or by auction	Zonal
MAPP ISO	Late 1999	FERC filing in fall 1998	IA, MN, NE, ND, MT, WI., SD, IL	Under investigation. May be part of ISO or separate.	Multi	Filing for utility facilities to be in ISO in preparation.	Redispatch all users share costs. Rate 110% of costs or $100/MWh	Zonal, flow-based pricing
Alliance ISO	N.A.	In planning. FERC filing expected in 1998	MD, MI, NC, OH, PA, SC VA, WV	Initially, ISO is PX. May be separated.	Multi	100 kV and up	LBMP	Zonal

[a] General characterization of ISO-controlled facilities; many higher- and lower-rated facilities may be included or excluded. Source: Adapted from Independent Transmission System Operators and Their Role in Maintaining Reliability in a Restructured Electric Power Industry, ICF Resources Inc. Prepared for U.S. Department of Energy, January 1998, and "ISOs: A Grid-by-Grid Comparison," Public Utilities Fortnightly, January 1, 1998, pp. 44-45. Updated by the author of this paper. Information on the DesertSTAR, MAPP, and Alliance ISOs should be viewed with caution, as negotiations over their formation are ongoing, and provisions may change. "LBMP" means locational-based marginal pricing.

Including the California ISO, FERC has approved or conditionally approved four ISOs in all, including the three ISOs filed by the NY, PJM, and New England power pools to comply with Order 888. All four include a central power exchange for matching buyers and sellers, although the ISO and power exchange are separate entities in California but are integrated in the NY, PJM, and New England ISOs. Designing a power exchange and incorporating it with an ISO may incur considerable costs—about $400 million in California alone.[3] For this reason perhaps, the newer ISOs under consideration or filed before FERC are "transmission-only" ISOs that do not include a power exchange. Proponents of these ISOs believe power exchanges will form on their own, as private market participants seek to maximize buying and selling opportunities and lower their transaction costs. Indeed, the NY ISO believes multiple power exchanges will form in addition to the exchange integrated as part of the NY ISO.

ISO PROVISIONS OF INTEREST TO BIOMASS

Availability of Transmission Services

An interesting characteristic of ISOs is that many stakeholder groups participate in the formation, organization, and oversight. Though the power and responsibility of stakeholder groups differ among ISOs, these stakeholder groups generally call for more types of transmission services and pricing arrangements than the usual firm, non-firm and network transmission service that has governed the electric power industry for years.

It appears that, through the formation of ISOs, the electric industry may introduce new varieties of transmission service beyond the usual firm, non-firm, and network transmission service. For example, the MAPP ISO will offer non-firm transmission service and allow service to continue during times of transmission constraints, but will impose a congestion charge of up to $5 per megawatt-hour (MWh). The MAPP transmission tariff is still being developed, but presumably a generator may opt to go off-line rather than pay the congestion rate. In addition, however, a generator that offers reverse power flows to relieve congestion may pay little or no congestion charges; in fact, they may get paid for their efforts to relieve congestion. Furthermore, though Order 888 requires that firm transmission service be made available for periods as short as one day, at least one ISO—the NE ISO—is offering firm transmission service for periods as short as 1 hour.

[3] It is important to realize California was starting from scratch in creating both an ISO and a power exchange, as well as consolidating the control centers in the state to one, which most ISOs are not doing. The ISOs associated with tight power pools probably did not incur such significant costs as there were elements of power trading and regional transmission already in place.

Nevertheless, there are signs that, along with greater flexibility, there also may be a countervailing trend to impose greater conditions on transmission users than in the past. For example, the proposed Desert Star ISO may require users of non-firm transmission service to have reserve capacity available as back-up, which is unusual for non-firm service. Such restrictions may indicate the level of discomfort transmission owners are experiencing as they move into a market structure with more players and non-traditional entities.

If there is more demand for transmission capacity than available supply, generally all of the ISOs allow for firm transmission service to displace non-firm transmission, and for longer-term firm transmission service to displace shorter-term firm transmission service. Holders of non-firm or short-term firm transmission capacity may be offered the opportunity to upgrade their service if they are going to be displaced otherwise. Therefore, biomass companies deciding to use non-firm or short-term firm transmission service need to be aware they are subject to displacement.

While there has been some momentum in offering more flexible transmission service, there also has been a counter movement in collapsing the types of firm and non-firm transmission service into one kind of transmission service that would be available for all transmission customers and owners. With the advent of open access, transmission owners have expressed concern that transmission users may take advantage of point-to-point or flexible point-to-point service and occupy transmission capacity at peak times at low cost. Or, alternatively, for transmission systems with lots of transmission capacity, transmission owners worry that transmission customers may purchase only non-firm service, knowing their service will never be interrupted, but also not contributing to the fixed costs of the transmission system. For this reason, momentum has built among transmission owners to try to convert transmission users to a single transmission service, generally network service. Yet collapsing transmission service into a single service may conflict with the desire of some to have the most flexible transmission service possible. FERC recently rejected the NE-ISO’s motion to eliminate point-to-point transmission service and have all transmission customers on network service (FERCa 1998).

Ancillary Services

In Order 888, FERC directed that transmission owners offer transmission customers six ancillary services, with two provided only by the control area operator. The six ancillary services are scheduling, system control and dispatch, reactive supply and voltage control, regulation and frequency response, energy imbalance, operating reserve/spinning reserve, and operating reserve/supplemental reserve. Only control area operators can provide the first two ancillary services. FERC expressed concern that there may be only a few ancillary service providers and required that ancillary service tariffs be filed at FERC at “just and reasonable” rates until further notice. Recently, FERC said it is open to proposals for market-based pricing of ancillary services (FERCb 1998).

There appear to be two ISO models for ancillary services. One is a daily competitive market auction for ancillary services, conducted or facilitated by the ISO. This is the approach commonly used by ISOs with power exchanges, such as the PJM and NY ISOs. The second model is one in which transmission customers or owners provide ancillary services, with the ISO acting as a provider of last resort. The California ISO and PX plan a competitive auction for ancillary services, but the California ISO also has some must-run contracts with generators, both to protect reliability and to ensure ancillary services are provided.

So far, the market for ancillary services appears to be relatively thin, at least in California. There are few participants bidding to supply ancillary services. In fact, the California ISO recently received permission from FERC to file new rates and provisions for regulation service, out of concern that not enough of this ancillary service was being provided.

Because biomass is a dispatchable, high-capacity technology, and could provide ancillary services that would create a small complementary market. Biomass could provide a number of ancillary services, such as regulation, operating reserves, voltage control, backup supply, load following, and perhaps black start service. However, ancillary services could be costly for some biomass plants if the plants are not effective at power regulation or trip off-line frequently. New biomass power plants should be designed to take advantage of ancillary service markets. In addition, some expect that a market for ancillary services will not emerge until FERC approves market-based pricing for such services. Recent work at Oak Ridge National Laboratory suggests pricing for ancillary services could differ significantly under a market-based pricing structure as compared to an embedded cost pricing structure (Hirst and Kirby, 1997).

Congestion Management

Congestion can occur if the sum of energy bids or transmission transactions is greater than available transmission capacity; some form of mitigation is required. So far, ISOs have proposed two approaches: (1) to assume any difference in energy costs between two locations is attributable to congestion, and charge parties for those congestion costs. This approach is referred to as locational-based market pricing or LBMP, or (2) do out-of-merit dispatch and assign the costs to all transmission customers, or to the transmission customer that is contributing to transmission congestion.

LBMP measures the price of energy at two different points. Its basis is that there should be no difference in energy costs between two points other than for transmission constraints. If there were differences between the two points, then lower-cost energy would be transmitted to that point, driving the cost of energy down to where the costs at those two points would be the same. If there were constrained transmission, then the

price at the two points could differ, because lower-cost energy cannot get to certain parts of the transmission system because of transmission constraints. The difference in prices between the two points is attributed to congestion, and parties with bilateral contracts using the congested lines must pay congestion charges if their transactions are to go forward. If transmission constraints become severe and congestion charges are correspondingly high, then some believe that transmission customers would move to expand transmission capacity in some way. FERC has approved the LBMP in the PJM ISO and the NY ISO and is being considered for the Alliance ISO.
The California ISO also relies on the difference in energy costs between two points to determine whether there is congestion or not. The difference is that if there is congestion it triggers a series of communications between the ISO and the affected scheduling coordinators to try to resolve the transmission constraint. The ISO sends the affected scheduling coordinators an adjusted bid schedule to alleviate the constraint. The scheduling coordinators may send back an alternative schedule or accept the ISO's schedule. If the constraint exists even with readjusted schedules, then the scheduling coordinator must pay the congestion charges.

The NE-ISO and the proposed Midwest and MAPP ISOs plan to redispatch or do out-of-merit dispatch if there is transmission congestion, and either assign the additional congestion charges to all users of the relevant ISO, or to the transmission customer that causes the congestion. Though some believe that having all users pay for congestion charges may not send the correct economic signals by not assigning the charges to those causing the congestion, this method is administratively simple and may work well if congestion is infrequent. The MAPP and Desert STAR ISOs are also considering whether to solicit reverse power flows to relieve congestion.

Besides congestion pricing, attention is also being paid to the development of transmission congestion contracts (TCCs). These are financial instruments that direct parties to pay some sum in advance in exchange for avoiding congestion charges for a certain amount of capacity. In addition, some ISOs are proposing transmission capacity rights (TCRs), which are considered defined rights to a certain amount of transmission capacity. The biomass industry may wish to carefully follow the debate in congestion, although it is not clear what the impact of congestion charges may be.

Other ISO provisions

Some believe that biomass companies may be able to enter into direct bilateral contracts with customers, which could allow longer transmission contracts and perhaps avert the need to bid into a power exchange. However, most ISOs require parties engaged in bilateral contracts to notify the ISO, and to let the ISO know whether they will pay congestion costs or not. As essentially guarantors of regional reliability, transmission owners assert that the ISO must be aware of all transactions in a region.

ISOs also typically encompass transmission facilities of 100 kilovolts (kV) or more, or in some cases, ISOs may encompass a smaller set of larger transmission facilities rated at 230 kV or more. Transactions involving facilities not in the ISO would be covered under the transmission owner’s own open access transmission tariff. However, which facilities are in an ISO and which are not can change, depending on use.

One significant element of Order 888 is the “unbundling” of generation, and ultimately of transmission, in retail competitive markets. That is, customers will take advantage of competition among power generators to select their power supply, then use a utility’s transmission system to deliver the power. In essence, the formerly bundled transaction of generation and transmission has changed to unbundled transactions of generation and transmission. In Order 888, FERC determined it has jurisdiction over unbundled transmission. Therefore, if more regions in an ISO go to retail competition, then more transactions may take place over transmission and distribution facilities, and these facilities may become part of the ISO. The MAPP ISO proposal foresees this possibility and allows the ISO to control distribution facilities in individual cases at the transmission owner’s consent. The NY ISO also allows for participation by generators wishing to transmit directly to retail loads if the load or supply exceeds 1 MW. Other ISOs will allow transmission to retail loads only if there is a filed retail transmission tariff, or if the transmission owner voluntarily provides the service.

The California ISO and the proposed MAPP ISO exempt facilities with less than 10 MW capacity; those facilities sell straight to local distribution companies. Biomass companies seeking to avoid an ISO or power exchange may wish to keep their facilities small, use lower voltage transmission lines, or sell only part of their power into a power exchange.

THE MARKET EXPERIENCE SO FAR WITH ISOs

ISOs should help biomass because access to a greater and more regional market will now be possible. Although a transition stage is necessary, eventually biomass companies may be able to transmit biomass power into a regional grid while paying a single transmission rate. Access to these larger markets may help biomass companies find more customers and markets. ISOs, however, should not be seen as either favoring or not favoring greater biomass power development. The roles of the ISO are necessarily broader, i.e., facilitating reliability, matching demand and load, resolving system constraints, conducting transmission planning, and providing information on system conditions to market participants.

The advantages ISOs offer to biomass companies—easier transmission access and single, regional transmission pricing—are also advantages for other generators and marketers, meaning competitive forces will continue to intensify for biomass as ISOs take hold. This is particularly apparent in the ISOs that include or are paired with power exchanges. In

California, prices bid into the power exchange have generally been below 3 cents per kilowatt-hour (kWh), with some hours of zero during off-peak times. Indeed, the California Energy Commission reports that prices bid so far in California are likely too low for new gas-fired generators, which represent the technology and fuel to beat these days. These very early results should be viewed very cautiously; the California market opened quite recently on March 31, 1998, and data is very limited (California Energy Commission, 1998). The three investor-owned utilities are required to bid into and buy their power needs from the California PX, so there is a large proportion of rate-based facilities essentially bidding their running costs. In addition, El Nino resulted in a very good hydro year for California, which also has depressed market prices.

The situation is somewhat different in the Pennsylvania-New Jersey-Maryland spot market, where prices have been more volatile. Maximum marginal clearing prices were as high as 16 cents/kWh in 1997, although the average marginal clearing price for the year was 2.12 cents/kWh (PJM System Coordination Division, 1997). It is important to note that the maximum price, however high, may be for extremely short periods. Higher price volatility is expected in a restructured market, though, and biomass generators should be selling when those peaks hit. From this perspective, competitive electric markets may look like retail markets, which stay open all year but retailers make most of their profits the few weeks before Christmas. Ancillary service markets may also short- and medium-term market opportunities for biomass generators equipped to provide these services. Nevertheless, policy measures may be necessary if new biomass electric capacity is to be added.

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